CALIFORNIA
ENERGY
COMMISSION

# AN ACTION PLAN TO DEVELOP MORE DEMAND RESPONSE IN CALIFORNIA'S ELECTRICITY MARKETS

DRAFT ACTION PLAN

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# Executive Summary

This action plan was developed to help stimulate a comprehensive review of existing rate structure and metering policies with the goal of achieving a more efficient and secure electricity market by achieving more demand response.  Demand response refers to the capacity of electricity customers to reduce their consumption as prices rise on an hourly basis in wholesale markets or to reduce their consumption in response to emergency calls when system reliability is threatened.  The plan has already achieved its initial goal by stimulating the joint adoption of orders instituting rulemaking and information gathering at both the California Energy Commission (Energy Commission) and the California Public Utilities Commission (CPUC) within weeks of its publication.

This final version of the plan includes our initial vision of how to get California's policy makers and electricity suppliers working together again to secure reliable and affordable electricity service and presents the feedback we received on that vision in initial public workshops.  This final version also contains a useful checklist of the types of problems that must be dealt with in the ongoing rulemakings as well as a useful source of reference material to help resolve implementation and timing issues.  What follows is a summary of the lessons learned during the preparation of the report and discussion of key themes at workshops.

**Regulators Need to Focus on Improving the Customer Side of a "Competitive" Market**

The numerous financial and legal scandals related to the potential exercise of market power in California's electricity market has deflected or misdirected the state's focus from an equally important and strategically far more important problem:

> *Why was there virtually no reduction in electricity peak demand from the customer side of the market when wholesale prices increased by a factor of five in less than a week in the summer of 2000?*

The reality is that customers did not respond by reducing demand, with disastrous consequences, because the infrastructure to transmit price signals from markets to customers was not in place. This led to enormous opportunities for suppliers to take advantage of an inelastic demand curve by raising their bid prices.  And they did.

The goal of this action plan is to ensure that customers are equipped with information about market prices so that they can respond immediately and greatly increase the observed elasticity of demand and thus the state's capacity to restrain price increases in the wholesale market. Competitive markets cannot function effectively unless both buyers and suppliers are both aware of and have the capacity to react to price signals.  It is ironic that the retail price freeze designed to protect customers probably left them more exposed to the exercise of market power and ultimately higher prices that the price controls were supposed to prevent.

History has shown that wholesale market prices for electricity, move up and down based on a variety of factors in both regulated and deregulated markets. In reality, no government can legislate the direction or magnitude of commodity prices such as electricity for more than a few months. In retrospect the state's focus on the end desired in 1996, lower electricity prices, allowed "reformers" to bypass a far more critical issue, what process or means would be used to achieve a **stable** wholesale market price in the transition from regulated to deregulated retail markets. In short, the regulators focused on the design of half of the market, the supply side, and **assumed** that the demand side of the market would take care of itself. Indeed by failing to provide pricing information to customers, the government may have transformed what could have been a sharp but short wholesale electricity price increase, into an ongoing financial nightmare complete with rolling blackouts when suppliers were not paid. This occurred because retail prices were not adjusted to reflect increases in wholesale prices, leaving the state's distribution utilities to "finance the difference" and ultimately undermining their financial creditworthiness and dramatically reducing their capability to "solve the problem".

**Developing More Demand Response Capability is Feasible and in Society's Best Interest**

Fortunately our analysis suggests that many of the problems encountered during the transition to competitive markets can be prevented in the future. Customers can be provided with the advanced metering equipment and control "tools" needed to effectively respond to changing market prices by reducing demand within hours, and not weeks**,** of any future supply crisis. The state and its utilities can give customers more power and control over their monthly energy bills by upgrading their metering systems from the antiquated magnetic meters of the twentieth century into the sophisticated pulse interval meter systems that will be deployed throughout the twenty-first century.

The analysis in this paper shows that deploying advanced metering systems and dynamic rates can provide Californians with many types of benefits:

- an estimated 2000 to 4000 Megawatts (MW) in permanent peak load reductions during hot summer days,
- hundreds of millions of dollars in operational meter reading savings for utility companies,
- increased levels of customer service through more precise outage detection and repair,
- increased reliability and lower wholesale prices through better asset utilization, and
- rate structures that better reflect their desired level of price exposure risk.

This paper identifies a series of action steps designed to help regulators balance these monetary and environmental benefits with the costs of deploying new meters and tariffs.
The opportunity now exists to provide all Californians with electricity pricing options that allow them to choose the mix of control equipment, interval meters, and/or rates to substantially reduce their own risk of paying more for electricity while at the same time dramatically reducing the risks of system wide outages. Time will tell whether the leadership of the electricity market is ready to seize this opportunity to give customers an equal chance in this market or will remain focused on fighting yesterday's "generator" wars.

# Section 1:  Introduction - What is Demand Response and is More Needed in Electricity Markets?

This report lays out an action plan to minimize, if not eliminate, the possibility that tenfold electricity price increases in the wholesale market could ever again be maintained over a period of days or even months in California.  Staff welcomes continued comments and input from all interested parties on the plan as part of the recently adopted Order Instituting Hearings on Demand Response.

This report is divided into seven sections: Section 1 introduces the concept and describes why policy actions are needed to increase demand response, Section 2 describes the roots of the problem, Section 3 describes the size of the problem created by a lack of demand response, Section 4 describes our vision of how California electricity markets may evolve over the near and long term, Section 5 describes barriers to the implementation of more demand response, and Section 6 outlines both the suggested action plan presented by staff at workshops and stakeholders reaction to it.  Finally, Section 7 contains suggested next steps and priorities for implementation of the action plan.

**What is Demand Response?**

Demand response refers to the capacity of electricity customers to reduce their consumption as prices rise on an hourly basis in wholesale markets or to reduce their consumption in response to emergency calls for curtailment or reduced load to forestall the need to implement rolling blackouts.  Demand response happens naturally in most markets because suppliers have the flexibility to raise and lower prices based on a variety of market factors and customers respond to these prices by adjusting usage or seeking substitute products.

Electricity pricing is significantly different than pricing for other commodities for two reasons: (1) proposed retail price increases must be approved by regulatory bodies, and (2) electricity cannot be purchased in advance or stored very easily at the customer level.  Thus customers must rely on regulatory bodies to quickly pass changes in the wholesale market through to the retail market so that they can “respond.”  Unfortunately, most customers don’t have the option of seeking substitutes for high priced electricity in the short run.  As a result, customers must have access to underlying wholesale electricity prices to be in a position to effectively “respond” to changing prices long before they see their next electricity bill on a monthly basis.  Unfortunately, the California market still lacks the basic metering infrastructure to support sending price signals to customers.  This lack of infrastructure and tariffs helped exacerbate the price spikes of 2000 as shown below.

**Why was there no Effective Demand Response to Higher Prices Experienced in the Years 2000 and 2001?**

Primarily there was no demand response because customers lack access to price information. Unfortunately, wholesale price information was not made available to customers in California during 2000 and 2001 in response to fears that the prices observed in the market were not just and reasonable.  It is instructive to consider why customers have not been provided with wholesale price information in the past and why these wholesale prices are no longer available to the public.

For years an individual customer's ability to reduce electricity demand in response to changing prices was not considered important because retail prices did not change more than once a year and significant changes in wholesale prices on a daily or monthly basis were not passed through to customers.  Customers had the luxury of responding to changes in electricity prices within planning time frames ranging from weeks to months.  However, with the development of "deregulated" wholesale supply markets in California wholesale prices began to change dramatically on an hourly basis.

In theory in a competitive market, retail rates should track changes in wholesale market prices on at least a lagged basis to ensure that markets can function by reducing demand when prices rise and brought downward pressure on rising prices by reducing demand.  In practice, retail electricity rates were frozen by the legislature and later by the CPUC so wholesale price changes could not be passed through to retail rates until it was too late, in June 2001, after 12 months of price volatility.

In the interim, customers had to rely on third parties and or "make shift" emergency programs to provide intermittent signals that wholesale electricity prices were headed up.  Moreover many customers did not have the requisite metering equipment to partially reduce their load in return for energy or capacity payments offered.  Without price signals and the equipment to react to them, crude all or nothing demand response in the form of turning off the electricity for some customers via rolling blackouts became not only important but vitally necessary to ensure system reliability.

In sum, the California wholesale electricity market was not demand responsive during the summer of 2001 and 2002 for two critical reasons:

1. Customers lacked the metering and controls equipment or technology to effectively respond to changes in prices in the relevant time frame.

2. Changes in wholesale prices were not automatically passed through to retail customers due to the retail price freeze.

Efforts to reform this market by addressing these problems came too late to discipline or restrain wholesale price spikes on both the supply and demand side.  Significant reductions in customer demand in most of the California did not appear until six to nine months after the wholesale prices first spiked in the summer of 2001.  Ideally, customers who saw a 200 percent price increase would have reduced their aggregate demand levels by 4,000 to 5,000 MW **within minutes to hours** of the first price spikes in May 2000.  (Assumes a short run price elasticity of 10 percent.)  What actually happened was that peak demand levels did drop by 4000 to 5000 MW but on a time scale of months not hours.  Peak drops of this magnitude actually occurred nine to twelve months later in May 2001.  Unfortunately, this "demand response" was well after the electricity crisis had peaked and billions of dollars had been transferred from consumers to producers.

One of the lessons learned from the experience in the California markets is that it is crucial that customers or aggregators of customers have the capacity to protect themselves from wholesale price volatility through the purchase of futures hedges in supply contracts or energy controls equipment that will allow them to respond quickly to changing prices, since timing is everything in competitive wholesale markets.  This protection is arguably superior to relying on regulators to discipline the market through the introduction of price caps.

Competitive markets cannot function without customers who have both access to timely price signals and the capability to reduce their aggregate demand as prices rise.  Without these customer capabilities, the demand for electricity or any other commodity is very inelastic and affording producers essentially a license to make "free" money by raising prices without any fear of losing revenues due to corresponding reductions in demand in the relevant time frame (e.g., within the next few hours on the wholesale market).  How much money the producers made during the crisis and how it might have been different if more demand response capability had been installed in the system is the topic of the next section.

# Section 2:  The Roots of the Problem

This section discusses why the underlying costs of generating and distributing electricity varies seasonally and by time of use and why this market reality has not historically been reflected in retail rates.

Power production and or the cost of purchasing imported power during periods of peak demand for most utilities ranges from 5 to 20 times the cost of producing electricity during the majority of the year or in "baseline" load conditions.  Indeed over half of the annual generation costs are incurred over only 10 percent of the operating hours when costs rise during system peaks.

Figure 1 and Figure 2 illustrate the fundamental fact that the cost of producing electricity to meet peak demands ranges from 5 to 15 times more expensive than the cost of production for the remaining 90 percent of the year for many distribution companies.  Figure 1 presents actual data from the Pennsylvania, New Jersey and Maryland PJM system.  (Reference 1)

Figure 1

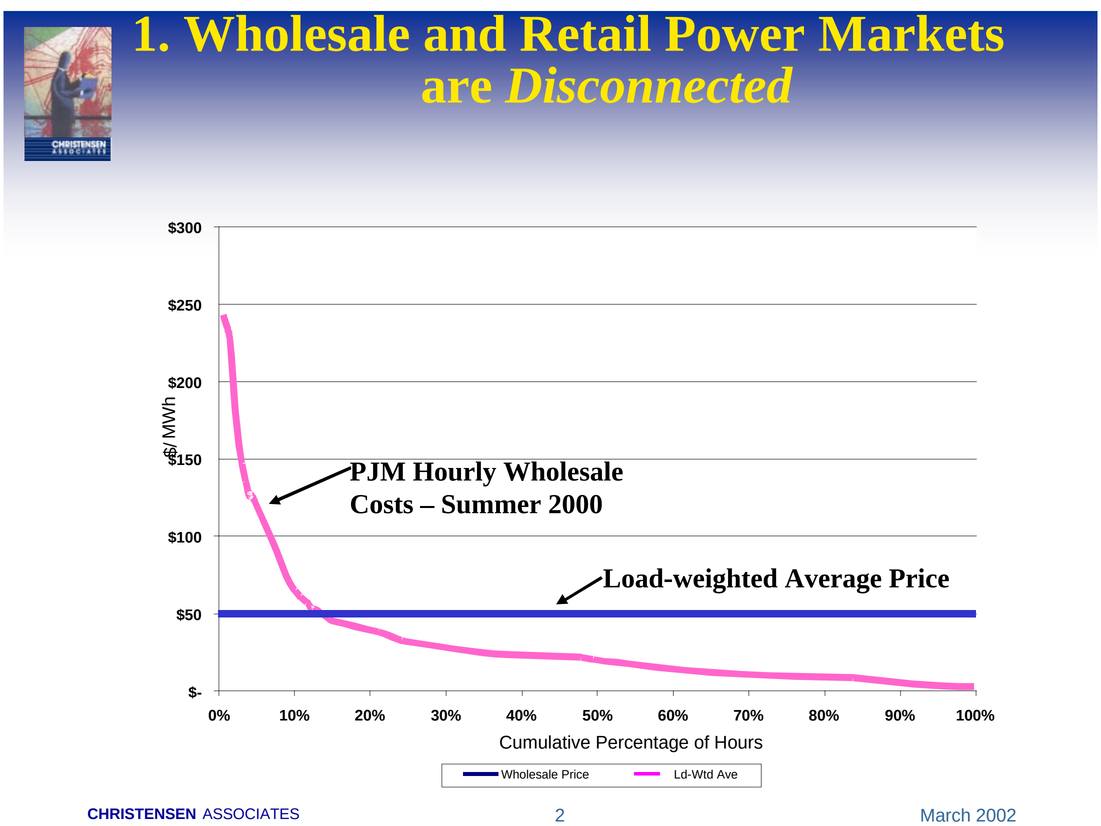
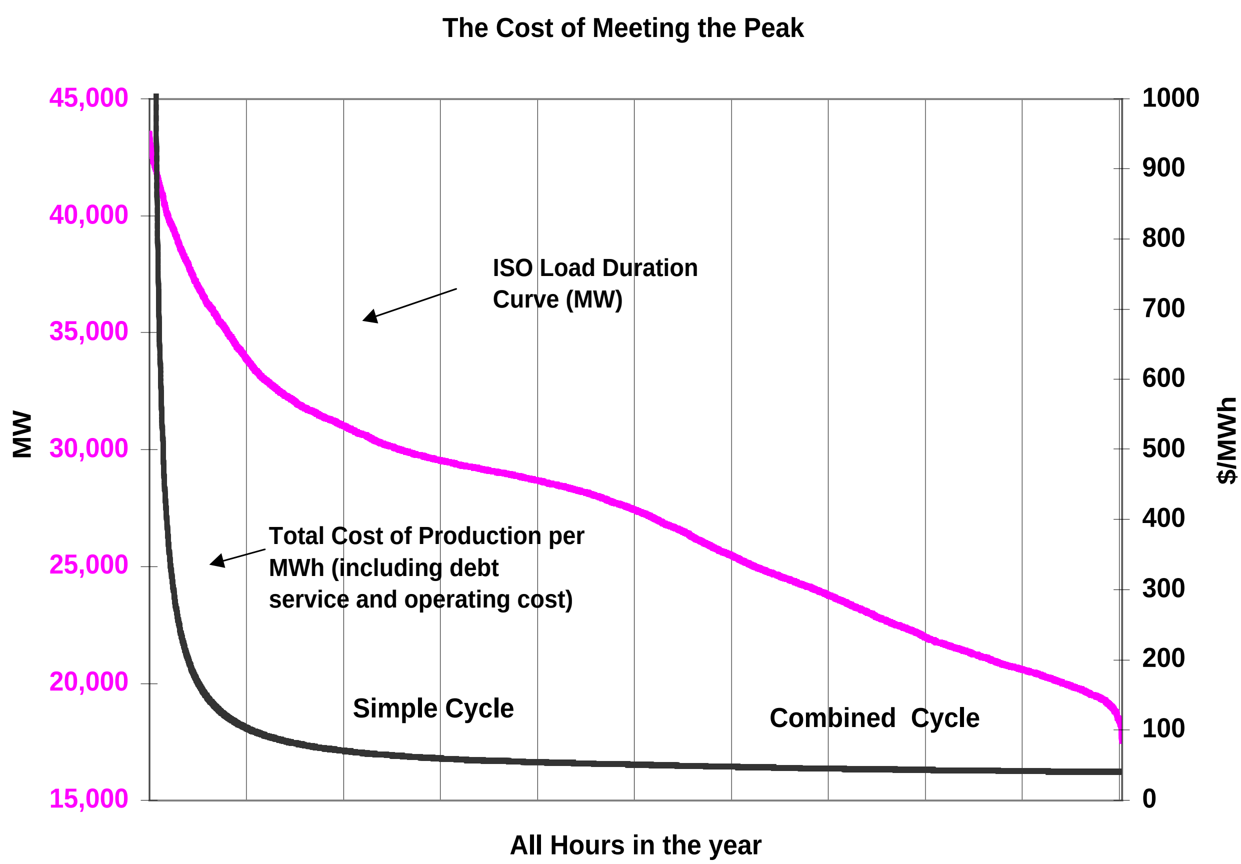


Figure 2 presents the estimated generation costs for the California system at different levels of demand. (Source: Pat Macauliffe, Energy Commission staff) By comparing the graphs we can see that the pattern of high costs per megawatt hour (MWh) to meet "needle" peaks occurs in many distribution systems and occurs whether or not the wholesale market contains unregulated generators or regulated, vertically integrated monopolies.

Figure 2




These higher production costs for generation resources or imports operated during the 50 to 100 hours of peak demand have historically not been revealed to customers by increases in retail rates at the time of high wholesale costs but rather rolled into the total operating costs for the year. Thus, price changes in the wholesale market were not routinely passed through to customers in the retail market.

This practice of "rolling" short periods of high wholesale price costs into retail rates "averaged" over an entire year made sense in a regulated environment because most generators were constrained from raising prices above costs during times of scarcity at peak. However, in a competitive market where generators are seeking to maximize profits this inability to adjust demand levels in response to price increases places all customers at a disadvantage since generators need not worry about potentially losing sales volume as they bid up prices in the short run.

## Customers have not been allowed to choose what level of price risk they want to accept in their standard or default rate structure.

Over the last 50 years regulators have chosen to approve flat rate structures with no capability to buy insurance against future price increases. This choice was considered prudent because regulators believed they could prevent any significant price spikes through prudent resource planning. With the transition to a competitive generation market, there is a higher risk of price volatility that can either be mitigated by distributors buying hedges for all customers or individual customers purchasing their own hedges. We believe that customers should be able to choose their own rate structure and associated levels of price risk (just as they do for insurance policies or cell phones). Shielding customers from "unacceptable" market price fluctuations inevitably leads to rationing solutions (e.g., blackouts for selected customers) rather than investment in new technology. Customers should be offered rate choices that allow them to choose between paying premium prices for flat tariffs or being willing to expose themselves to more price volatility in return for lower prices overall.

## The current market structure is inequitable because there are barriers to entry for customers or "demand" aggregators who wish to actively participate in the wholesale market.

Customers and aggregators of customer load have not been allowed to participate in wholesale markets on an equal basis with power generators. For example, customers are not allowed to bid block of curtailment or reduced load into these markets as prices rise. This difficulty stems from the assumption that customers must look like and act like power generators before they are eligible to bid in the wholesale market. The markets for ancillary services support and capacity reserves are beginning to be made available to all bidders in some wholesale markets but aggregators face significant market risks due to uncertainties in policy direction and lack of capital for business start up relative to their generation competitors.

## The current market clearing prices for electricity no longer reflect the market's demand for stable electricity supplies. The market prices are unstable and a deterrent to investment in demand response capability.

Between 2000 and 2001, wholesale markets in California have witnessed two extreme conditions. In 2000 almost 70 percent of total power purchases flowed through the spot markets. In the summer of 2002 less than one percent of California's power requirement was flowing through the same spot markets. The current prices revealed in shallow (low volume) wholesale markets are not likely to reflect the true marginal costs of supplying additional power because of the imposition of FERC price caps. The Federal Energy Regulatory Commission's (FERC) decided to intervene in these short term markets until a more rationale mix of long, medium and short supply contracts were executed. This decision had the short-term beneficial effect of stabilizing wholesale prices. However, the false sense of security provided by these retail price caps represents a longer-term threat to system reliability in California since marginal prices are no longer revealed to all market actors. These price caps and the threat of their re-imposition will make it more difficult to predict the effect of increased demand response capability or drops in load during critical peak periods.

Demand response providers in the form of aggregators of customer demand response could be allowed compete on an equal footing with suppliers to provide ancillary services. FERC has recently begun to move ahead in this area with the introduction of a standard market design, which calls for the development of significantly more demand response.

## Federal and state regulators have not been able to agree on the best way to fix a dysfunctional wholesale market.

To put it mildly, the federal government and Western state governments fought in 2000 and 2001 about the merits of different methods of reforming the supply side of the market while virtually ignoring the possibility of stabilizing the market through the use of demand response tools. The federal government has focused on attempts to reform the structure and rules of the wholesale "bidder's" market while many state regulatory commissions have pushed for wholesale and retail electricity price caps as a temporary mitigation measure. Unfortunately, reforms focused on suppressing "false" price signals to consumers, often based on the belief that customers should be protected from the high prices that result when supplies conditions are tight or that refunds should be available if customers think the prices were in retrospect, too high. The reality is that customers will have to pay their bills, regardless of whether the charges are just.

## State agencies have had limited success in achieving a consensus on the need to stimulate more demand responsiveness in the California market.

The Energy Commission and CPUC have had different priorities in responding to the crisis. The Energy Commission has focused on getting more price and energy efficiency information to the customers while the CPUC has focused on fixing market power problems that have led to high prices. On the state level the failure to achieve more demand responsiveness is, in part, structural, because of the existence of energy and planning agencies with overlapping jurisdictions related to system reliability and procurement, and in part financial, due to the need for the CPUC to focus on utility creditworthiness problems rather than reforming the demand side of the market. Fortunately, the energy agencies in California have a historic opportunity to work together to solve this market problem because for the first time there are a number of outside organizations encouraging them to work together for the good of the whole. For example, the Energy Commission, CPUC, and CPA have begun to work together to develop a unified policy for demand response and energy efficiency programs.

## Summary

The flat electricity rate structures offered by utilities to almost all customers mask, and in some senses subsidize, the real cost of producing electricity during peak periods.  This policy made it impossible for customers to rationally respond to rising prices in the wholesale market in a timely manner during the summer and fall of 2000 and the spring of 2001.  The failure to disclose changing prices to customers and the subsequent lack of demand response from customers contributed to the high prices and profits reaped by generators in the California market from May 2000 to June 2001.  Any attempt to reform the wholesale market must address the underlying infrastructure and pricing problems revealed on the demand side of this market in addition to addressing the strategic behavior or withholding witnessed on the supply side.

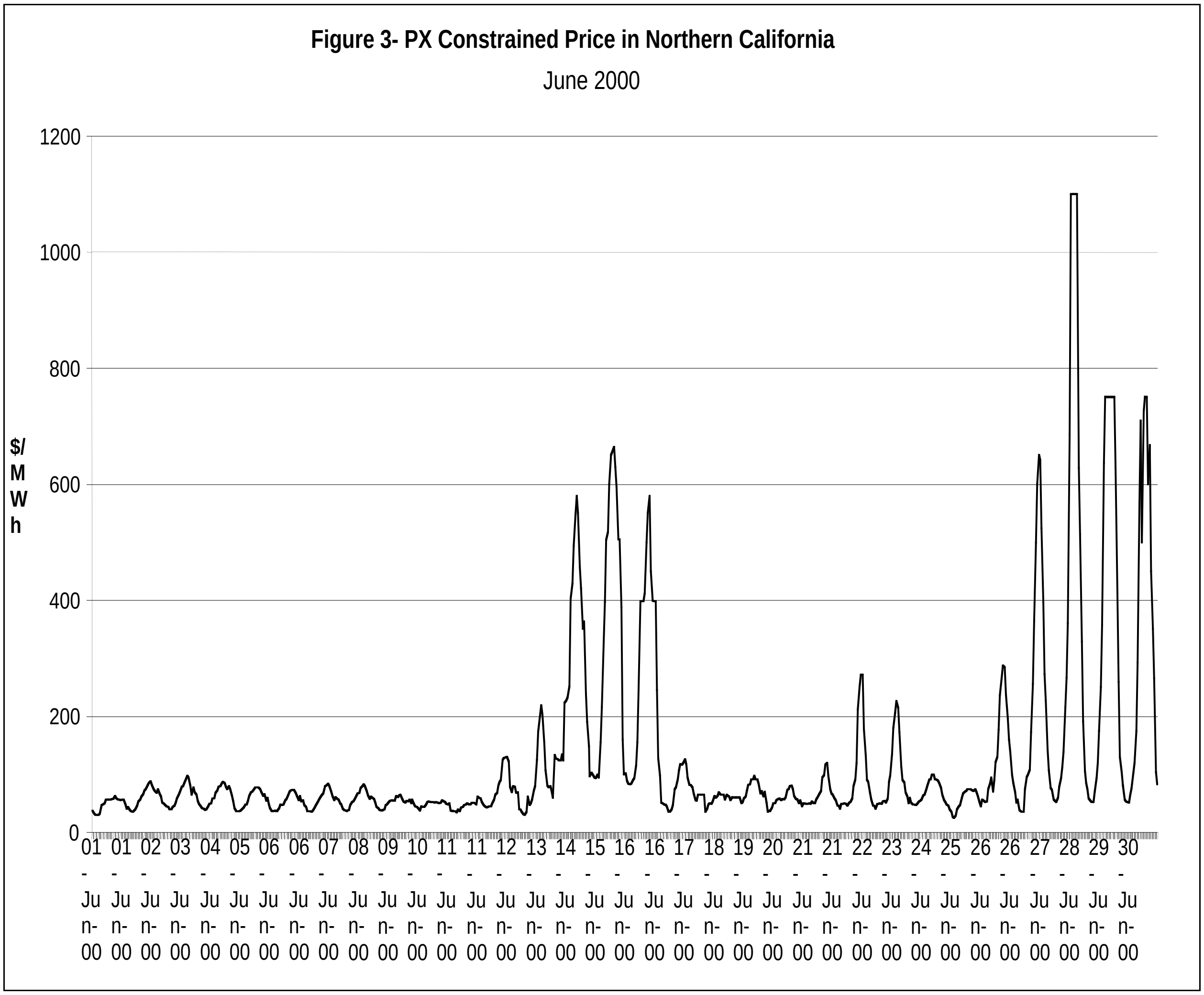
# Section 3: The Cost of the Problem

## How Much Money Could Have Been Saved if Demand Response Programs and/or Dynamic Pricing Had Been in Place in California Last Year?

This section compares three methods for estimating the cost savings that could have been achieved by customers if demand response programs and dynamic pricing programs had been in place before the summer of 2000. We start by reviewing trends in the actual wholesale prices over the last two years and data on customer elasticities to estimate the likely range of customer response if wholesale prices would have been linked to the retail market.

California experienced extreme price volatility in wholesale electricity markets in 2000 and 2001. Figure 3 illustrates this pattern for June of 2000. One of the reasons for the extreme price volatility is that these new markets for supply were not demand responsive within minutes to hours, i.e., when prices went up there was no corresponding drop in consumer demand within the hour or in some cases within days of these price spikes. As a partial result of this lack of demand response, the total bill for utility power purchases nearly quadrupled from $7.4 billion in 1999 to $27 billion in 2000. Total electricity costs stabilized at $26.7 billion in 2001 even though the average cost per MWh was slightly higher at $114 per MWh in 2001 than the $107 per MWh reported for 2000. This was due in part to lower electricity peak demands in the summer of 2001 and in part due to the imposition the FERC price mitigation (caps) that set a price ceiling of roughly $98 per MWh beginning in June 2001.

Figure 3




It is possible to estimate the reductions in demand that would have occurred if customers had actually paid the prices experienced in the wholesale market rather than the frozen retail prices in place at the time.  Estimating how much demand (and wholesale prices) might have been reduced is difficult because of the possibility that some suppliers were price makers rather than price takers during some of the supply emergencies.  However, it is possible to either construct an aggregate demand curve based on the prices and quantities observed in this market.

We provide a discussion of three ways to estimate the benefits from increased demand response capability below.

- Method 1 - Assume that the changes in wholesale market prices from 2000 were passed on to retail customers and estimate the corresponding reduction in demand and market prices using historical price elasticities.  (Source:  Reference 2, McKinsey, 2000)

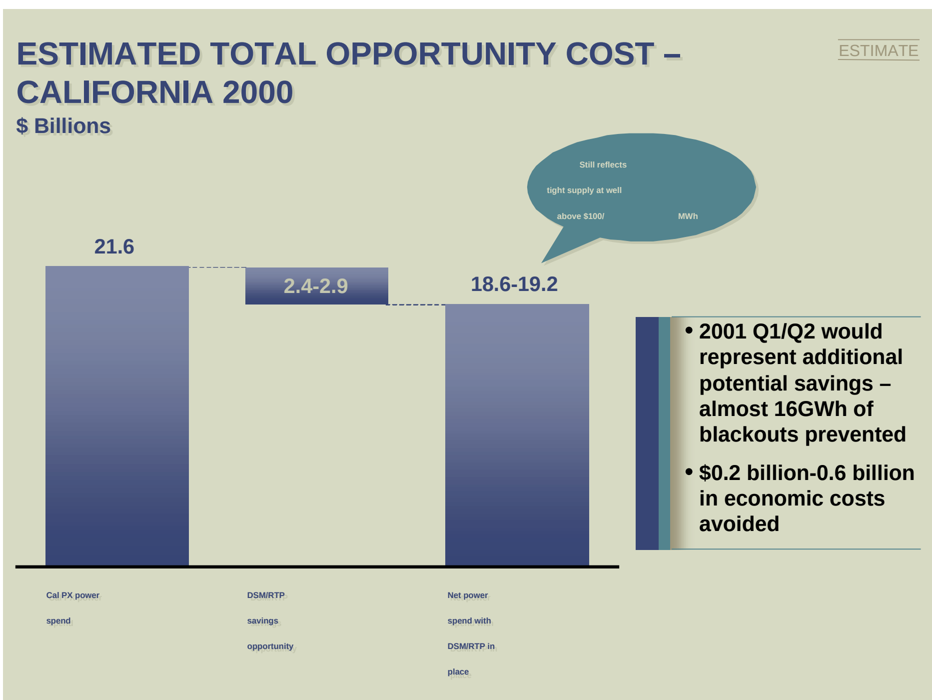
- Method 2 - Estimate the actual elasticity of demand and supply using CPX data for the 12 months in 2000 and then determine the dollar savings associated with incremental levels of demand reduction. (Source: Energy Commission staff)

- Method 3 - Analyze the costs of operating new peaking facilities during the 20 to 100 hours of needle system peaks in today's market and estimate the marginal value of saving increments of peak demand at the margin by avoiding these costs next year and beyond. (Source: Energy Commission staff)

## Method 1 - Assume that the variations in wholesale price observed in the market were instantaneously passed on to all customers in rates and use historical price elasticities to estimate the corresponding reduction in demand and dollar savings

Figure 4 displays the results of an analysis from McKinsey Consultants to estimate the savings from additional levels of demand response. This study was commissioned by the Association of Bay Area Governments. (Reference 2) Their analysis suggests that the observed wholesale power costs of $25.2 billion for California in 2000 would have been reduced by somewhere between $2.4 and $2.9 billion if hourly retail electricity pricing had been in effect for medium and industrial customers. In addition, McKinsey estimates that the 5 percent reduction in peak demand levels would have precluded the need to use rolling blackouts to preserve grid integrity in the spring of 2001.

Figure 4

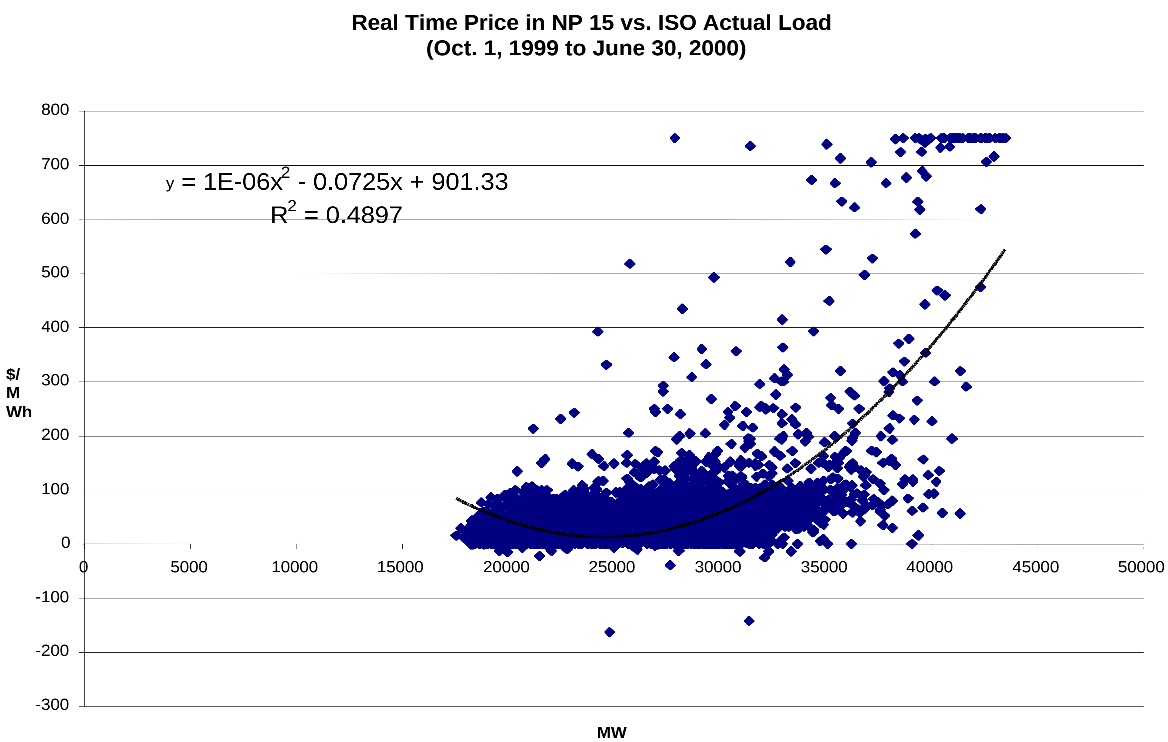


## Method 2 - Use historical price and quantity data from the California market in 2000 to estimate the value of reducing peak demand at the margin

Method 2 estimates the potential dollar savings resulting from reductions in peak demand that reduce wholesale prices and thus revenues paid to generators. Historical data is used to construct a demand curve and estimate the drop in wholesale prices for a given level of demand reduction that could be achieved by programs or dynamic tariffs. The first step is to plot the observed prices and quantities of electricity when price controls were not in effect from October 1, 1999 to June 30, 2000.

Figure 5 shows the estimated demand curve for Independent System Operator (ISO) loads and real time prices in Northern California for this time period.

Figure 5




There is a lot of scatter in this graph because of a variety of strange things were happening on the supply side of this market, but one can see a definite upward trend in prices as demand increases. When an exponential fit line is used to analyze this data, the $R^2$ is almost 50 percent. This suggests that roughly 50 percent of the price variation in this plot can be explained by "rational" expectations that market prices will rise as demand increases and vice-versa. The other 50 percent of the unexplained variation relates to other factors at work in this market (e.g., market power, poor market design, strategic withholding) that may have been an historical accident or simply the fact that wholesale prices were not passed on to customers in a timely manner. The equation is a two term exponential equation where the demand x can be used to predict the wholesale price. Evaluating the fit line for the range of load in excess of 32,000 MW, a linear fit suggests a change in price of $35 per MWh per change of quantity of 1,000 MW. This price change relationship holds for all peak demand changes in the range between 32,000 and 45,000 MW.

Table 1 shows the estimated impact of different levels of demand reductions on wholesale prices. The table uses the estimated slope of the demand curve to estimate different wholesale price levels (and the resulting total revenue requirements that would result) as the cumulative amount of demand response is increased. This analysis suggests that a modest amount of demand response (2000 MW) could reduce the wholesale prices from $70 to $280 per MWh while a substantial increase in peak demand reductions within 1 hour of a price increase could have reduced the wholesale down to the baseline price of $80/MWh.

This calculation is conservative because it only looks at changes in wholesale prices that could be expected on the ten typical peak days in California when peak load exceeds 40,000 MW. In reality, more dollar and peak savings could have been realized if customers were placed on dynamic rate structure on a daily basis where changes in wholesale prices would automatically be passed on to customers on each day of the year rather than the ten hottest days.

**Table 1**
**Change in Wholesale Market Prices as a Function of**
**Aggregate Demand in the CAISO Load Control Area**

| Hypothetical Demand Response Program Impacts (MW) | Baseline Price<br>$/MWh | Estimated Price Drop as a Function of Demand Response<br>$/MWh | Expected System Savings from Drop In Wholesale Prices<br>($ Million)[1] |
|---|---|---|---|
| ***Baseline condition - 40,000 MW*** | ***370*** | ***0*** | ***0*** |
| Demand response (DR) during peak conditions = 2000 MW (current programs produce 1500 MW) | 300 | 70 | 168 |
| DR peak = 5000 MW (current programs + voluntary hourly pricing industrial) | 205 | 165 | 420 |
| DR peak = 8000 MW (voluntary residential critical peak pricing and voluntary hourly pricing for medium and large customers) | 90 | 280 | 672 |
| [1] $ savings = change in peak demand (MW) *predicted change in price ( $/MWh) * 6 peak hours/day and 20 peak days per year when demand exceeds 40,000 MW | | | |

For reference, California utilities estimated that the aggregate capability of their load management programs in the spring of 2000 was roughly 3000 MW with most of this capacity coming from interruptible rate programs. Available capacity had dropped to 1500 MW after extensive use of interruptible rates from January to May 2001. (See Appendix A for a chart of reported demand response capability over time.) Metering advocates estimate that demand response in California could easily be increased by an additional 5000 MW if 30 percent of large and commercial customers were allowed to join dynamic tariffs (either hourly or critical peak pricing). (Reference 3, Chris King, 2001)

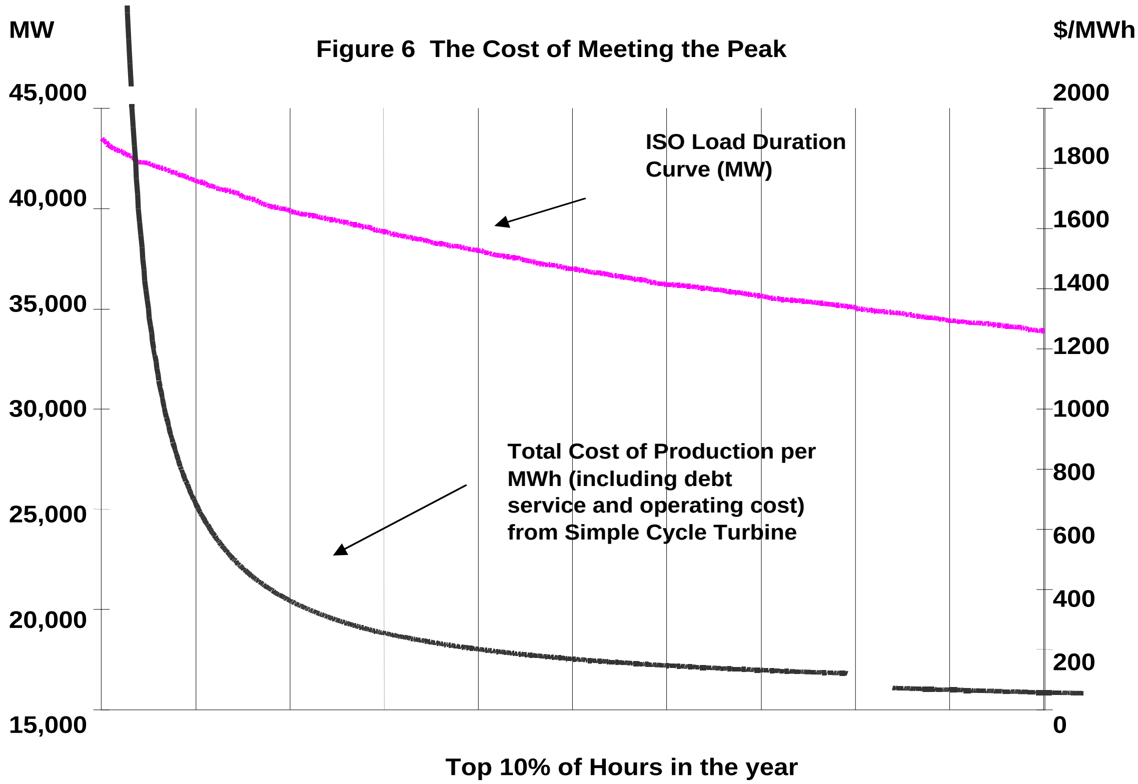
Unfortunately, the existing "demand response" capability of California's utilities has been primarily designed to reduce demand during emergency conditions and as a result was used only a few times in the last two years. The maximum peak load drop ever achieved through the use of interruptible programs was 1730 MW on May 8, 2001. (Source CAISO report on ISO Declared Emergencies of 2001, Reference 4). Utility load management programs have not been used to mitigate or restrain wholesale prices. The sum of the aggregate peak load drops from both interruptible curtailable rate and direct control programs never exceeded 2000 MW on a statewide basis. Thus wholesale prices have rarely if ever been constrained by downward pressure in demand levels when prices are rising.

## Method 3 - Using the cost of operating combined cycle gas turbines during peak conditions as a proxy for the value of demand response at the margin.

Method 3 estimates the value of demand response at the margin by looking at the avoided costs not operating peak power plants during peak demand conditions. Figure 6 below estimates the total annual costs of operating a peak power plant (simple cycle turbine) including debt service plus fuel use (depending on output) and divides by hours of operation (1, 2, 3,…) to arrive at an average cost of production ($/MWh) depending on numbers of hours of plant operation.

This analysis suggests the cost of the gas fired peaker plant (and thus the value of demand response at the margin) is over $1600/MWh when demand exceeds 40,000 MW in California. This analysis illustrates the cost of meeting peak demands if the system operators chose to fund the construction of peakers but only operated them for 50 to 100 hours per year as opposed to seeking more demand response through programs, bids or prices.

Figure 6




## Summary of Expected Value of Load Reductions

This analysis of the effectiveness of drops in demand at the margin shows that the impact of reducing peak demand at the margin on wholesale prices ranges from $35/MWh (Method 2) to $2000/MWh (Method 3). Currently the state lacks the capability to actually achieve these wholesale price drops because there is no set of programs or tariffs in place with a significant capability to reduce load at the level of three to five thousand MW as prices are rising in wholesale market. The peak level of peak load reduction achieved by all of California's demand response programs in response to emergency signals during March 2001 was less than 2000 MW. Our analysis shows that using dynamic price signals to all commercial and industrial customers could have reduced demand by 3,000 to 5,000 MW, reduced wholesale prices by 15 to 20 percent, and obviated the need to call emergencies absent additional withholding behavior from marginal generators.

This analysis of the value of demand response at the margin is conservative because it does not account for the actual benefits to California's economy or customers of avoiding rolling blackouts. Rolling blackouts are the most extreme form of demand response programs, e.g., mandated total load curtailments with less than one hour notice and no alternatives. Estimates of the cost to the economy or commercial firms of blackouts currently exceed $10,000/MWh.

Our review of the data suggest that increasing the state's demand response capability to 5000 MW has the potential to significantly reduce wholesale market costs. Estimates of the level of annual benefits from a demand response program based on 2000 data range from $420 million (see Table 1) to $2.9 billion (Reference 2), without accounting for any estimate of the damages avoided by virtually eliminating the need for rolling blackouts. In addition, demand response programs and or dynamic tariffs have the potential to significantly reduce, if not eliminate, the need to resort to rolling blackouts if or when adequate suppliers are not available in the wholesale market. These potential benefits of deploying dynamic tariffs and interval meters on a large scale of roughly 5000 MW need to be balanced against the costs of deploying these systems.

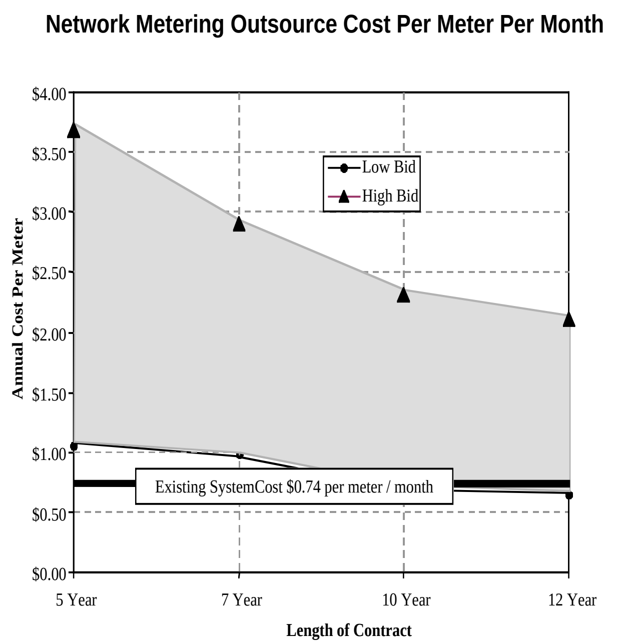
## Costs of Installing Interval Metering Systems

### Interval Meter Costs for Large and Medium Customers

The cost of installing a large number of advanced or interval metering systems depends on the number of systems to be deployed, the communication medium to be used, the built-in software capabilities to monitor and display energy usage, the type of customer and the length of the contract provided to meter service providers. The Energy Commission's experience in procuring interval meters and communication systems for medium and large commercial customers suggests that the range of meter cost bids range from $1.00 to $3.70 per meter per month for a five year contract to a range of 70 cents to $2.60 per meter per month for a 12 year contract. See Figure 7 below an illustration of the trends in metering costs as a function of the length of the contract (Reference 5). This range compares to the estimated current cost of $.74/meter/month for traditional meters with no hourly or 15 minute data collection and transmission capability.

Figure 7

These figures suggest that large-scale deployment of these advanced interval meters may be cost competitive with existing meters without any consideration of the additional functionality and or demand response benefits associated with their use.  This conclusion is based on two conditions: (1) the new meters are purchased on a large scale (greater than 200,000 meters), and (2) their costs are amortized over a contract period of 12 years.




Note:  High / Low Range of Vendor Bids for 500,000 Electric meters to collect monthly billing data.

Source:  Compeititve bid, Investor Owned Utility,  +500,000 electric meters.

8

Meter System Costs for Small Commercial Customers

The total costs of installing meters for the remaining small and medium customers between 50 kilowatts (kW) and 200 kW can be approximated as $2.50/meter per month/ customer over 10 years multiplied by the 50,000 remaining customers, or $15 million dollars.  This total cost of $15 million can be compared to the projected benefits for installing advanced meters and developing critical peak tariffs for these same remaining customers.  These remaining customers represent 6000 MW of peak load or roughly 600 MW of demand response.  Using the lowest wholesale price drops from Table 1 for the value of demand response (at $35/MWh) yields benefits of $48 million per year or a net present value of $325 million over the ten year period.

Meter vendors have asserted that costs of installing advanced meters should be compared to their estimates of $6 to $8/meter per month of benefits from their deployment (Reference 3, Chris King). Chris King estimates that the social benefits of installing interval meters to all customers will exceed these costs even if only 30 percent of residential and small commercial customers actually sign up for a dynamic tariff. An interagency group should examine these assertions before the state makes a decision to universally deploy IDR meters for all customers.

Meter System Costs for Residential Customers

The costs of installing advanced metering systems and supporting communication networks in residential applications is not as certain. Puget Power and Light has had some experience in installing these meters and reports the costs of installing these meters has already been repaid by operational savings in less than 3 years (Reference 9, Gullekson).

A recent paper by Herter estimates the incremental cost of the interval meter itself will be around $100 per house. (Reference 10). The cost of communications, software, and temperature controls at the home are not yet known because of uncertainties in what end uses will be controlled. If we assume that only the HVAC system will be controlled via a communicating thermostat control, the incremental cost is estimated to be $50/ home in California and total cost would be $150 per house. By contrast some control systems can cost up to $600 per home if a Gateway for internet access is installed.

Gulf Power installed a gateway system for over 3000 of its customers to support a critical peak-pricing tariff. For this system residential customers pay $4.53/month for seven years (roughly $400) to cover the cost of the interval meter, a whole house surge protector, a smart thermostat and two controllers that can respond to critical peak prices by reducing consumption at up to two large end uses per home. Total installation costs are closer to $600/home suggesting the utility is picking up $200/home based on other benefits being produced by the system. (Reference 11, Brian White)

The actual costs of the advanced residential metering systems installed in California will depend on whether utilities purchase and install these systems in bulk and what fraction of the total costs are paid for by the utility as part of its “metering system” and what costs are paid for by homeowners for software, display, and control systems. However, this section’s analysis of the potential value of deploying these systems suggests the overall benefits are likely to be many times the cost estimates developed above. Before deciding exactly what types of system to install, it will be important to develop a vision of what functions or roles these new metering systems will have in the electricity market. To this task we turn.

# Section 4:  How to Achieve More Demand Response in the California Electricity Market

This section presents a vision of how to accelerate the adoption of dynamic tariffs and advanced metering systems to achieve more demand response in California.  It includes design principles to develop new tariffs, a description of possible rate structures and a vision of how the new meters will be integrated with rates and control systems to produce more demand response.

Californians expect their elected representatives and state government to work with the existing utilities and energy providers to develop a world class system of distributing electricity to customers that is reliable, efficient and consistent with their strongly held environmental values. Recent developments in technology and the explosive growth of the internet and wireless communications make it possible to provide customers with the means to both receive and respond to changes in prices in a manner that will both reduce electricity costs and reduce net emissions of pollutants to the atmosphere.  Businesses currently receive daily and sometimes hourly information on the costs of key inputs to their businesses but must wait over 30 days to find out how much their electricity will cost.  Upgrading the current metering and billing system to make billing and metering systems more intelligent and capable of managing bills will not only reduce private costs but significantly increase system reliability, reduce outage risk, mitigate market power, and reduce environmental threats to California's precious asset, the air we breathe.

The lack of demand responsiveness in the current electricity system not only fails to counter restrain wholesale price spikes but can bring the entire economy to its knees when the reliable supply of electricity is threatened.  The Energy Commission staff believes the Energy Commission and the Public Utility Commission should work together to bring the electricity system of California into the twenty-first century by making advanced metering systems available to all Californians by 2010.  Energy Commission staff plans to seize this opportunity and work tirelessly to bring Californians a success story on the demand side to help balance the recent "failures" on the supply side of the deregulated market.

The Energy Commission staff also recognizes that this transition cannot happen overnight.  The rest of this document lays out our strategies to work with industry providers, regulators, and the general public to devise the right transitional strategy to test and install the new meter system in the most cost-effective way possible.  But first it is important to clearly define the functional capabilities that we expect this new system to provide and our vision of rate structures and equipment.  After this we provide our recommended strategies to achieve more demand responsiveness in the electricity market

## Design Principles for the Dynamic Tariff System

We support the adoption of the following principles to ensure customers can access price signals if they want them and purchase controls equipment to respond to these price signals when they are not at home or at their business site.

> Principle 1 - Ideally the design of an interval metering and dynamic tariff system must provide for the free flow of price information to customers who desire access to the data, return usage data to system providers on instantaneous power demand and provide customers with the ability to purchase (or finance) "controls" equipment that can respond automatically to this information to help manage their electricity bills.
>
> Principle 2 - Customers should be given a choice of rate structures to empower them to either closely manage their own bills based on price signals, delegate this to an onsite management system, or delegate this management function to on-site or third-party providers who specialize in this business.
>
> Principle 3 - Rate structures should reflect the reality of underlying costs of providing and distributing energy to customers and provide the opportunity to hedge against future price increases.
>
> Principle 4 - New buildings should include state-of-the-art metering and control systems that can act automatically to reduce load and preserve the reliability of the distribution system in the event of local disasters, system breakdowns, or generation outages.

## Proposed New Rate Structures

Consistent with these principles, the following basic set of rate structures should be developed to match customer needs with system reliability concerns. All customers should be allowed to choose how they prefer to manage the risks of future electricity price increases by choosing either flat or variable rate structures. Our preference would be that time of use rate structures, or variations on this theme such as critical peak pricing, become the default rate for all customers. These customers can then choose to participate in one of the following three types of rate structures to better match their preferences for managing price risk:

- Voluntary base rate discounts coupled with critical peak pricing rates that could be dispatched for up to 80 hours per year during emergencies.
- Two-part hourly pricing tariffs for the large commercial and industrial customers.
- Flat rate structure for those customers who are willing to pay an additional monthly "Stability Premium" or hedge in exchange for the certainty of a flat rate over a one to five year contract.

We have focussed primarily on the development of dynamic tariffs because they are likely to be more cost effective than other demand response options. Analysis presented by Charles Rivers and Associates suggests that dynamic tariffs have a higher benefit to cost ratio than time of use tariffs or load control programs for utilities in Minnesota (Reference 8). Once these dynamic tariffs are developed, a transition plan will be needed to install the metering to support these tariffs for all customers. Our vision of the desired end state to guide this implementation plan is presented below.

## End State

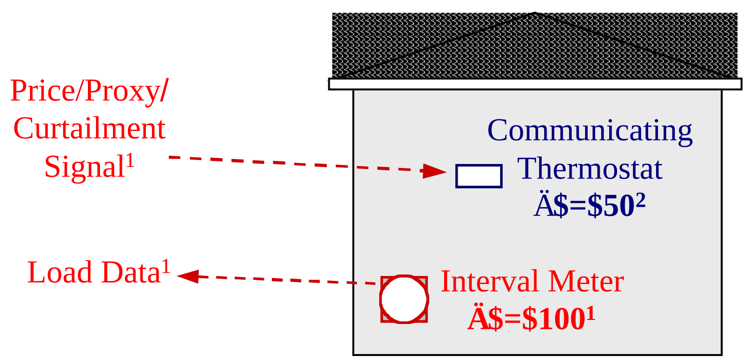
We propose that the CPUC change the default rate choice for residential customers from flat rates to critical peak pricing contracts that can be exercised for up to 50 hours per year. We envision a demand response program with smart thermostats will eventually be required as a condition of service for all residential customers with central HVAC systems. Under this program, all customers with central HVAC systems would require (1) a dynamic tariff, and (2) an advanced meter. A responsive one-way or smart thermostat would be installed that could trigger changes in thermostat setting based on price thresholds that are pre-programmed from home owners. This would allow customers to raise their thermostats and lower their bills at when they are not home once prices pass some pre set threshold, say 20 cents/kWh.

Figure 8 provides a schematic layout of what this new metering system would look like.

Figure 8

Proposed System for Demand Response
in New Homes & Small Commercial Buildings

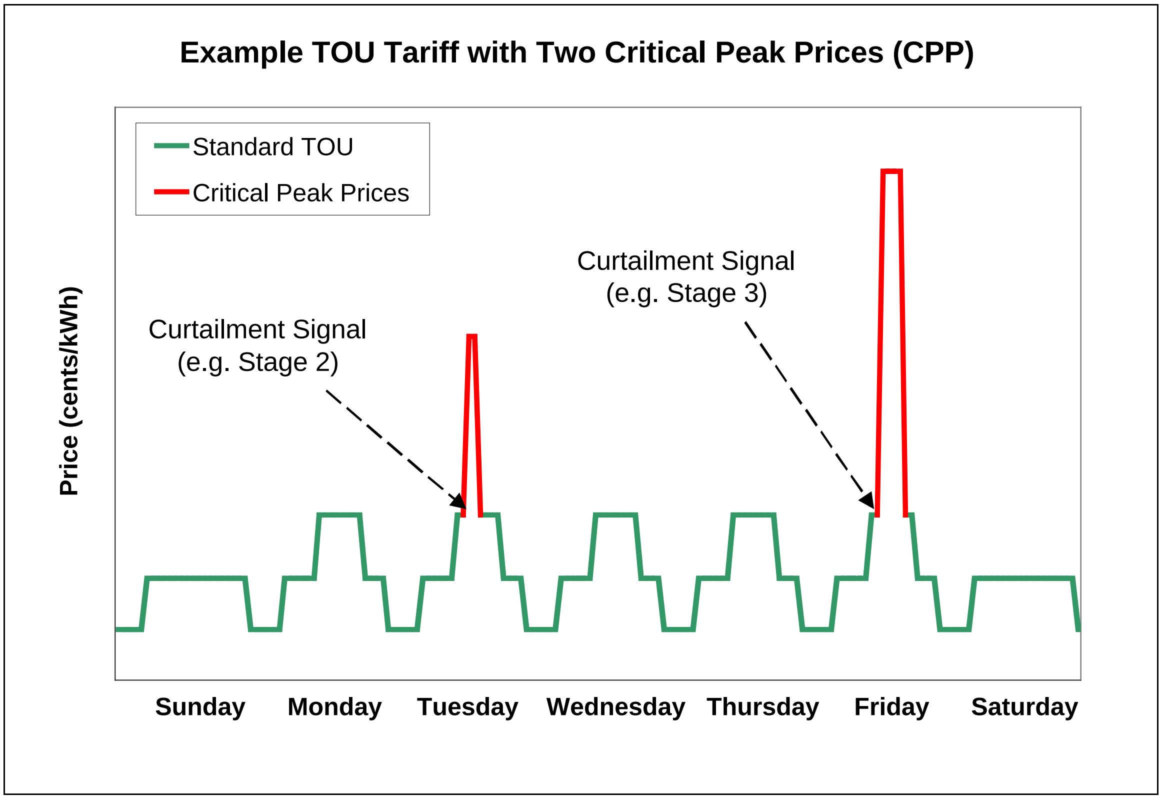
Cost of Avoided Load: $100-200 per kW




1. **Utility** responsible for signal, communications, meter, and load data.
2. **Builder** responsible for communicating thermostat.

To complement this infrastructure, we propose to make critical peak pricing tariffs available as a choice to all residential homes. Figure 9 provides a schematic of critical peak pricing rates. Under this rate, customers are offered a discount or lower rates for the vast majority of hours in the year in return for the possibility that critical peak prices may be charged for up to 50 hours per year when system reliability is threatened or wholesale prices begin rising dramatically (the red spikes on Tuesday and Friday in the figure). This type of pricing is a compromise between customers who want the certainty of flat rates and the suppliers of energy who must deal with the reality that wholesale prices frequently rise and their costs must ultimately paid by retail customers.

Figure 9



# Section 5: What are the Current Barriers to making this Vision a Reality

This section examines four types of barriers to achieving increased demand response in the electricity market that were identified and discussed during CEE's May 4th and May 15th workshops. These are grouped into four types: Policy, Technical, Administrative, and Marketing Customer Acceptance.

## Policy Barriers

The following is a list of policy barriers presented at the workshops and discussed by participants.

1. No common vision - There is no common vision among regulatory agencies and probably most key market actors of how the wholesale and retail electricity markets will/should evolve. A portion of this problem relates to disagreements about how to include the possibility of customer demand response within planning and procurement processes and whether it is a good idea to expose customers to time varying or dynamic tariffs.
2. Overlap - There is a jurisdictional overlap between independent system operators (ISO's) regulated by FERC and utility distribution companies regulated by state public utility commissions over who should design and approve programs to increase demand response in wholesale markets. This conflict exists because of the overlap between FERC review of transactions that occur in the wholesale market and the state PUC's review of the rates charged in the retail market to recover wholesale power costs.
3. Demand response needed in retail or wholesale markets? - This issue is even complicated because of the possibility that some customers are large enough to participate in wholesale markets by providing demand response via contracts while most smaller customers participate in demand response programs in the retail market. Currently, it is not clear whether federal or state organizations have responsibility to develop different types of demand response programs or to make dynamic tariffs available to customers to ensure either system reliability and/or reasonable prices.
4. Legacy load management programs - Historically the development and approval of load management programs has been the role of state public utility commissions as part of their charge to ensure high quality service to retail customers at reasonable rates. When these programs proved ineffective in the new market structure, new market participants proposed demand response programs at the wholesale level. For example, the New York ISO (NYISO) and Pennsylvania, New Jersey and Maryland (PJM ISO) have asserted that design of demand response programs and tariffs is part of their mission to oversee the development of rational wholesale markets and thereby ensure reliability. In 2000, the CAISO developed some demand response programs but had to suspend their operation due to creditworthiness problems beyond its control. In other areas, state public utility commissions have retained jurisdiction over emergency programs at the retail but not the wholesale level. In California both state and federal agencies have developed and approved various forms of demand response programs.

5. Cost effective - Some regulators are skeptical that dynamic tariffs and/or the deployment of interval metering equipment to make them work would be cost-effective for society. Others are skeptical that customers will really want access to dynamic pricing tariffs or to purchase equipment to control their loads in response to changing prices.
6. Impact on wholesale prices - Uncertainty remains about whether demand response programs will actually create downward pressure on wholesale prices in today's "non-competitive" markets. An evaluation of the NYISO demand response programs showed that their emergency demand response program produced a steady 450 MW of load drop during heat storms and three percent drop in wholesale prices (Reference 6). There has not been any analysis of the price impacts of using California's demand response programs impacts during the winter and spring of 2001. Energy Commission staff has begun this analysis with partial results shown in Section 3.
7. Re-regulation as an alternative to demand response - Some state regulators assert that the wholesale market does not need to be fixed as long as there is an option to return to a more regulated market that could "control" or discipline these markets. These regulators see no need to have, or develop, price responsive demand or dynamic tariffs in the retail market since they were not needed in the previous regulated market.
8. Lack of a real time market - There is no functioning wholesale market in California to provide hourly pricing signals or day-ahead forecasts of hourly prices. However, once implemented, ISO Market Design 2002 proposals have the potential to solve this problem by providing reliable day-ahead and real-time dynamic pricing signals.
9. Interaction of demand response programs and reserve margins - It is unclear how, or whether, dynamic pricing tariffs and price-response demand programs can be counted toward satisfying Western States Coordination Council operating reserve requirements.

## Technical Barriers

1. Controls too expensive - Digital energy management control systems that can communicate with meters and system scheduling coordinators are still considered too expensive by many commercial owners and builders. The incremental cost of installing dimmable lighting systems is still considered too high by most builders ($40-$50 per ballast) to justify their expense as part of new building projects. In addition, some utilities have been skeptical that wireless metering technologies have been demonstrated to be reliable, cost-effective, particularly in urban areas where transmission shadows can inhibit data transfer.
2. Need for uniform control language - The lack of an agreed upon uniform control language for EMS systems creates some communication problems with existing HVAC and lighting systems.
3. Uncertainty in predicting the level of price response - Immaturity in the "art" of estimating the extent of peak load reduction that may result from an emergency reliability signal or price signal reduces interest on the part of system operators and energy procurement agents.
4. Customer friendly displays needed - To facilitate more customer participation, load visualization and alarm techniques, and automatic control equipment must continue to evolve to make demand response concepts more "user friendly."

## Administrative Barriers

1. Billing system capacity constraints - Some utilities could have trouble providing reliable billing services to their customers using dynamic pricing tariffs. This is because existing billing systems are not equipped to handle a large increase in the number of data points collected for each customer. Utilities will probably need a long-term decision to deploy advanced meters on a universal basis over five to ten years to deploy the resources necessary to solve this problem.
2. Multiple demand response programs - Multiple types of demand response programs are currently offered by utility distribution companies and private aggregators to the public. To complicate matters these programs are overseen by different energy agencies. Several commentators have noted that the market is confused by the proliferation of both emergency and price responsive programs that are currently in the market place.
3. Uncertain market clearing prices - Disagreements on the value of energy or demand reductions from demand response program participants worsened during 2001 as new energy agencies and the CPUC could not find common ground on both what was to be valued (energy, capacity, day ahead calls, etc) or what it was worth.

## Marketing Barriers

1. Customers not interested in legacy programs - Most industrial customers are not interested in providing load reductions if it means interrupting service without warning through old-fashioned or legacy interruptible programs or in violation of the contract terms related to the duration of the interruption due to unforeseen emergencies. They would prefer to purchase other forms of insurance unless the programs become much more flexible and dependable.
2. Communications and marketing materials are not clear - Participants in California's demand response programs are quite frustrated by the lack of effective communication regarding the types of demand response programs to be offered on a consistent basis (for more than one summer) and inconsistent policies with respect to the assessment of penalties for non-performance (Reference 7).
3. Concerns about productivity - Many customers perceive that curtailing load cannot be accomplished without a significant drop in plant or personnel productivity. They are either unaware or not convinced that most building systems have the technical capability of reducing loads by ten percent with little or no effect on employee productivity.
4. Cost recovery for program expenses uncertain - Most utilities have expressed serious concerns (outside of regulatory arenas) about the prudence of spending money to recruit more customers into demand response programs or tariffs under the current regulatory regime where cost recovery is at best highly uncertain.

## Conclusions

The Energy Commission staff believes that most of these barriers could be quickly resolved over the next three years if the key policy agencies could agree on what how to resolve the policy barriers first and then let other players work to resolve the remaining technical, administrative, and marketing barriers. The next section describes some potential actions that could be taken by each agency to resolve these.

# Section 6: Proposed Actions to Mitigate or Eliminate Policy Barriers and Increase Demand Responsiveness in the Electricity Market

This section examines possible actions to mitigate or eliminate the policy, technical, administrative and marketing barriers discussed in the previous section. These action steps were discussed at two Energy Commission workshops in May 2001. During the workshops, we asked participants to rank the relative importance of each of these actions. Participants were asked to indicate whether they supported the action and its relative importance vis-a-vis other actions on a scale of one to five; a ranking of five indicated the action was the most important vis a vis other actions, a ranking of three was important but not critical and a ranking of one signified the action was not needed or necessary. We have added the average relative priority score based on the scores received from 27 market participants in *italics* after each action recommendation. After this numerical score, the status of the recommendation is provided in **bold text**. Information in this status section ranges from a staff recommendation to drop or no longer consider the action item to a recommendation to pursue the action by working with other state agencies or market participants

## Policy Barrier 1 - No Common Vision of Future Electricity Market Structure

Currently, there is no common vision held by key state agencies or the electric distribution utilities of where the electricity system is heading and how or if demand response should be included in that vision. Perhaps as a result, the state has not yet identified how and where the planning and implementation of demand response programs should occur and or how they should be integrated with tariff proceedings.

**Action 1.1** - The Energy Commission, CPUC, CPA, and CAISO should work together to develop a joint vision of the role of demand response programs and advanced metering programs over the next decade. We suggest using the vision points presented in Section 3 as a starting place for more dialogue and a discussion of alternative visions.

***Relative Score = 4.36***

***Status - Action has been taken. The Energy Commission and CPUC are working together in a joint proceeding to examine tariffs and programs to achieve more demand response and how these actions should be linked with tariff and procurement proceedings***

**Action 1.2** - The Energy Commission, CPUC, CPA, and CAISO should make a commitment to integrating demand response programs or tariffs into the re-design or reform of wholesale electricity markets in the form of a letter to the Federal Energy Regulatory Commission (FERC) announcing their plans to achieve demand response in the new market design.

***Relative Score = 4.4***

***Status - No action yet. State agencies have different opinions on the need to inform the FERC of their action by letter and if this step would achieve any positive results.***

**Action 1.3** - The Energy Commission, CPUC, and CAISO should meet to discuss how to develop a joint demand response planning forum or series of coordinated policy proceedings that would set policy and approve programs over a multi year period.

***Relative Score = 4.0***

***Status – Action taken. The Energy Commission and CPUC are discussing this recommendation informally within the joint proceeding on dynamic tariffs and advanced metering - No formal action is needed at this time.***

## Policy Barrier 2 - Jurisdictional Conflicts Between Regulatory Agencies

There may be a jurisdictional conflict between the CAISO and the California Public Utility Commission for design and approval of demand response programs/tariffs.

**Action 2.1** - Have a neutral third party (perhaps the Energy Commission or California Power Authority) propose a division of oversight responsibilities. This organization might identify clear areas of oversight based on primary agency functions and secure a commitment for both agencies to meet where programs overlap.

One analyst proposed that the CAISO should have jurisdiction over "reliability based" programs to provide spinning reserve, and capacity reservation commitment from customers for emergencies, (examples: CPA spinning reserve proposal, Optional Binding Mandatory Curtailment and or direct load control). The CPUC should have jurisdiction over all price based response programs (including demand bidding, baseline demand response, and interruptible curtailable programs) and all dynamic pricing tariffs. The CPUC and CAISO could announce that they plan to work together and expect utilities to analyze and propose the appropriate mix of demand response programs and tariffs as part of their "resource or reliability" plans to be reviewed in the CPUC's procurement proceedings.

***Relative Score = 2.7***

***Status - Action was dropped for the short term based on the possibility that this jurisdictional conflict is being worked out.***

## Policy Barrier 3 - No Perceived Linkage Between Falling Aggregate Demand Levels and Falling Wholesale Prices in a "Broken" Market

Some dispute exists about whether the use of demand response programs and or dynamic tariffs will actually lead to significant reductions in electricity prices at the margin in the wholesale market. This dispute is exacerbated because there are no transparent wholesale electricity markets in California with enough sales volume to actually observe changes in wholesale prices as a function of demand.

> **Action 3.1** - The Energy Commission and CPUC should work closely with the CAISO and CPA to ensure that whatever market design reforms are adopted produce a transparent wholesale market by January 1, 2003. A task force should provide quarterly status reports on the status of efforts to recreate wholesale price signals that should be delivered to the heads of each state energy agency.
>
> ***Relative Score = 3.2***
>
> ***Status - Recommendation on hold, pending review of a FERC decision on CAISO market redesign proposals (that includes re-establishment of transparent prices in day ahead market).***

## Policy Barrier 4 - No agreement on Need to Develop Dynamic Pricing in a "Stable Electricity Market"

No policy agreement exists on the best way to develop and implement a system of dynamic pricing tariffs for all customer classes and how to link the wholesale market prices to these tariffs for some or all classes.

> **Action 4.1** - The CPUC and Energy Commission should jointly announce their intent to move toward making dynamic tariffs available to all customer classes within the next decade.
>
> > **Action 4.1a** - Hold workshops to develop model dynamic pricing tariffs for at least four customer classes, present to the CPUC by January 1, 2003.
> >
> > **Action 4.1b** - Expand the current procurement proceeding in Phase 2 to perform an analysis of the need for dynamic tariffs to be phased in beginning by June of 2003.
>
> ***Relative Score = 4.0***
>
> ***Status – These three Action steps have been taken with adoption of joint Order instituting Rulemaking (OIR's) on demand response by both agencies.***

## Policy Barrier 5 - Advanced Interval Meters Installed Without a Complimentary Dynamic Rate Structure

The current state policy related to the purchase and financing of meter improvements has not yielded a commitment by distribution companies or state energy agencies to deploy interval meters to the mass market. The Governor's metering program to install advanced interval meters for customers in the 200 to 500 kW class has not led to more momentum in this area to install meter in smaller rate classes. This problem may be related to the fact that no workable dynamic tariffs have been proposed for the residential or small customer class.

**Action 5.1 -** The CPUC and Energy Commission could announce their intention to design and implement a pilot program to test the effectiveness of critical peak pricing tariffs for a representative sample of customers in one or more IOU service territories. Expenses could be recovered using loan funds from CPA or through the rate base. Both agencies should carefully monitor customer acceptance and load impacts before moving ahead with decision to deploy the critical peak pricing tariff and interval meters and control equipment to support them on a system wide basis.

***Relative Score = 4***

***Status - No action yet. Critical peak pricing pilot is likely to be proposed within joint Energy Commission-CPUC proceedings on demand response.***

**Action 5.2** - Metering vendors could be asked to respond to a request for proposals (RFP) to deploy advanced metering systems to all customers in each IOU territory over a five-year period. The IOU's would select winning bidders and seek authority to recover the expenses of deploying the winning bids within the ongoing procurement proceeding.

***Relative Score = 3.7***

***Status - Action on hold pending results of cost-effectiveness analyses of potential advanced meter deployments in Energy Commission/CPUC proceedings.***

**Action 5.3** - State agencies could seek to amend the current senate bill on dynamic tariffs (Torlakson, SB 1976) to more explicitly support introduction of dynamic pricing over the next few years.

***Relative Score = 2.7***

***Status - Action dropped. The bill has been amended and signed into law by the Governor.***

## Policy Barrier 6 - Uncertainty About How Customers Can and Will Respond to Dynamic Pricing or Tariffs, Given New Opportunities for Automation.

Regulatory uncertainty exists about the costs and benefits of introducing dynamic pricing tariffs for some customers.

**Action 6.1** - Appoint an interagency staff team to both propose a set of dynamic tariffs for all customer classes and analyze the anticipated impact of these tariffs on demand and wholesale market prices and the related cost-effectiveness of the tariffs for specific customer classes. The team should use the vision on rates presented in Section 3 as a starting point.
***Relative Score = 3.8***

***Status – The intent of this action step has been achieved. Staff from Energy Commission and CPUC are working together to plan analyses necessary to achieve more demand response.***

**Action 6.2 -** Energy Commission, CPUC, and/or utilities could agree to task an expert team to investigate the feasibility of shifting the "insurance premiums" consumers currently pay as part of a flat rate to guarantee reliability, from a social allocation basis where the insurance premium is included in everyone's rate structure to a market driven basis where payment differs based on individual usage.

***Relative Score = 3.2***

***Status - No action yet. These issues will be considered within Energy Commission/CPUC proceedings***

**Action 6.3** - The demand response group or a neutral party could offer to brief any or all commissioners with questions about cost-effectiveness of achieving more demand responsiveness by presenting the results of the benefit cost analyses prepared by Charles Rivers Associates and presented at the workshop (Reference 9). This study showed that the deployment of meters and critical peak pricing led to the highest benefit cost ratios of any demand response/tariff mix (benefit cost ratios from the total resource cost perspective ranged from 1.7 to 3.5).

***Relative Score = 3.6***

***Status - Recommendation pending. No action taken pending the formation of a demand response group and need for briefings.***

## Policy Barrier 7 - Deployment of Advanced Meters is Not Needed if the Electricity Market is "Re-regulated"

Some regulators are not sure that the deployment of demand response programs or dynamic tariffs is consistent with their desire to move back to a regulated generation market.

**Action 7.1** - Demand response team should develop and prepare briefings for each CPUC, Energy Commission, and CPA commissioner on the costs and benefits of dynamic pricing in both regulated and deregulated markets. This briefing can be provided to key legislators on request. (Our analysis shows that demand response or dynamic tariffs are likely to be equally as important in ensuring system reliability in either regulated or deregulated markets.)

***Relative Score = 3.76***

***Status - Recommendation pending. No action taken pending the formation of a demand response team and assessment of need for briefings after draft decisions are issued.***

# Proposed Actions to Address Technical Barriers

## Technical Barrier 1 - Many Current Energy Management Systems are Incompatible with Dynamic Pricing

Builders see no current need to design energy management systems that can communicate with utility meters and system notification networks in the event of pending reliability problems. In addition, the cost of providing dimmable lighting ballast systems that are integrated into energy management systems is seen as too high and or not cost-effective.

**Action 1.1** - Energy Commission should begin a load management[1] proceeding by June 1, 2003 to set demand response goals at the system and customer/building level. Possible options to analyze include:

1. System wide standards that mandate that utility distribution companies demonstrate on an annual basis the ability to shed up to five percent of system load requirement capability within 30 minutes of a call.

2. Standards for new buildings could require each building to have the capability to automatically secure a ten percent load drop at the building level within 30 minutes.

3. Interval metering requirements could be required for all customers' classes over a five to ten year implementation schedule.

The goal would be to have new load management standards adopted by June 1, 2003 for use in the summer of 2003.

***Relative Score = 3.9***

***Status - Action taken. The Energy Commission adopted a demand response order on July 17, 2002 to examine these issues, but did not set out a specific time line to adopt new standards.***

[1] The Energy Commission's load management standards authority is described in Appendix 2.

**Action 1.2** - Energy Commission should include metering and controls requirements as part of its ongoing improvements to building standard proceeding for all new buildings after January 1, 2005. The Commission should consider requiring that all 100 kW or higher buildings meet the following requirements:

1. Interval meters and communication (wireless) systems.

2. Linkage of these meters to on site control of lighting and HVAC systems.

3. Some form of energy information system that provides customers with information on load profile and cost per hour at their facility.

***Relative Score = 3.7***

***Status - Recommendation pending. The Energy Commission anticipates looking at these issues within its recently adopted OIR.***

**Action 1.3** - Consider setting new building code requirements for single family homes and small commercial buildings (20kW to 100kW) including:

1. Interval meters and/or smart thermostats.

2. Specifying some minimum form of energy information system be made available to building owners either on site or on line.

***Relative Score = 4.0***

***Status - Recommendation pending. The Energy Commission anticipates looking at these issues within its recently adopted OIR.***

**Action 1.4** - Energy Commission and utilities should jointly sponsor additional Public Interest Energy Research (PIER) research to develop lower cost sensors and ballasts to drive down the current costs of energy management systems linked to dimmable ballasts.

***Relative Score = 4.0***

***Status - No action taken, PIER group at Energy Commission will consider these concepts in its next funding cycle.***

## Technical Barrier 2 - Perception that Advanced Metering Technologies Cannot Be Successfully Deployed for All Types of Customers

Some distribution utilities are skeptical that today's wireless metering technologies will prove to be reliable and cost-effective in all settings. Particular problems have been caused by large buildings in urban areas that create communication dead zones or shadows that slow or stop communication signals.

**Action 2.1 -** Prepare a report on the effectiveness of wireless metering technologies currently being installed in the SCE and PG&E territories and suggest any needed improvements in hardware or network support.

***Relative Score = 2.5***

***Status - Action dropped due to low score and priority.***

## Technical Barrier 3 - Uncertainty About How Dynamic Tariffs Will Effect Current Operating Reserve Requirements

Reserve requirements - It is unclear how, or whether, dynamic pricing tariffs and price-response demand programs should be counted to provide reserves that would satisfy Western States Coordinating Council operating reserve requirements.

**Action 3.1 -** Form a working group to explore dimensions of this problem with California ISO, Western States Coordinating Council members, and other interested parties.

***Relative Score = 4.5***

***Status – No action taken yet. Staff needs to identify a person to form the working group and identify options to intervene in Western States Coordinating Council process.***

## Technical Barrier 4 - Predicting Load Reductions Stimulated by Changes in Retail Electricity Prices is a Very Crude and Inexact Science.

Immaturity in the “art” of estimating the extent of load reduction that may result from and emergency signal or critical peak period price signal has reduced the interest of system operators and energy procurement agents in using demand response as a reliable source of reserves.

**Action 4.1** Build a better reporting system within the existing network of advanced meters that can measure combined price and program induced peak load drops at the substation level.

***Relative Score = 4.0***

***Status - Recommendation pending. Staff has reduced the priority of this project until more dynamic tariffs are developed and in place.***

### Technical Barrier 5 - Curtailment Strategies Perceived as Painful and Disconcerting to Participating Customers

Customers are not yet familiar with the concept of monitoring loads and responding to load curtailments without sacrificing comfort or productivity.

> **Action 5.1** - To facilitate more customer participation, load visualization and alarm techniques, automatic control equipment developers, and software vendors must work together to make demand response concepts more "user friendly." Staff plans to support the development of more user friendly energy management systems through the state's enhanced automation campaign.
>
> ***Relative Score = 4.5***
>
> ***Status - Action taken: The Energy Commission has produced guidebooks on how to enhance the automation of current control systems and is working with utility distribution companies to distribute these to customers and track actions taken to increase customer acceptance of the systems.***

## Proposed Actions to Address Administrative Barriers

### Administrative Barrier 1 - Processing of Large Increase in Data Flow from Interval Meters May Exceed the Capacity of Current Utility Billing Systems.

Billing Constraints - The state's utilities could have trouble, in the near term, billing their customers using dynamic pricing tariffs because of the significant increase in the amount of data that needs to be processed from each meter. Long and short-term strategies were discussed to deal with this problem.

> **Short Term Action 1.1-** Utilities should develop and test more complex billing systems for 100 to 500 customers before committing to universal deployment.
>
> ***Relative Score = 4.2***
>
> **Long Term Action 1.1** California's energy agencies should develop long term customer participation goals for demand response programs after the results of the pilot tests are reviewed.
>
> ***Relative Score = 4.7***
>
> ***Status - Recommendation pending. The need for and timing of pilot tests as well as the merits of setting long term participation goals will be addressed in the joint Energy Commission/CPUC proceedings.***

### Administrative Barrier 2 - Multiple "Emergency" Programs Offered by Independent Actors Tend to Confuse Customers

Utility distribution companies and private aggregators offer multiple demand response programs to the public. To complicate matters these programs are overseen by different agencies. Several commentators have noted that the proliferation of both emergency and price responsive programs causes confusion in the market place.

> **Action 2.1 -** Ask program managers to meet and recommend much more user friendly names and organizing concepts for the current range of demand response programs.
>
> ***Relative Score = 3.0***
>
> ***Status - Recommendation dropped. There is no apparent interest from program managers who attended the workshop in fixing this problem in near term.***

### Administrative Barrier 3 - Value of Emergency Peak Load Reductions is Uncertain

Disagreements on the value of energy or demand reductions from demand response program participants worsened during 2001 as new energy agencies and the CPUC could not find common ground on both what was to be valued (energy, capacity, day ahead calls, etc.) or what it was worth.

> **Action 3.1** - Solve this dispute as part of either the ongoing procurement proceedings at CPUC or as part of Energy Commission load management standards proceeding.
>
> ***Relative Score = 4.1***
>
> ***Status - Action taken. The Energy Commission and CPUC are working together in an attempt to develop common methods for estimating avoided costs at margin and value of capacity insurance.***

## Proposed Actions to Address Marketing and Customer Acceptance Barriers

### Marketing Barrier 1 - Developing Curtailment Strategies is Perceived as an Emergency Response and Not Part of The Normal Business Environment

Most commercial industrial customers are not interested in providing load reductions in response to emergencies or price signals on a day-to-day basis as the crisis fades. However, they may be interested if the rates are coupled with proposals to increase the use-enhanced automation to control energy bills and increase occupant productivity.

> **Action 1.1 -** Coordinate the deployment of the Energy Commission's existing enhanced automation campaign with utility distribution companies and other agencies to maximize

its effectiveness.  This campaign is scheduled to kick off on June 1, 2002 and will provide information and case studies to targeted users and keep interest in new metering and control high.

***Relative Score = 4***

***Status - Action taken.  Program materials are being distributed to customers and third party vendors.***

## Marketing Barrier 2 - Lack of Effective Communications and Long Term Policies Frustrate Large Users Seeking Higher Reliability in Service.

Large commercial and industrial users are quite frustrated by the lack of effective communications about what demand response programs will be offered on a consistent basis and inconsistent policies with respect to the assessment of penalties for non-performance.

**Action 2.1** - The state's energy agencies (Energy Commission, CPUC, CPA, and CAISO) should meet and confer to decide if the demand response message for summer of 2002 and beyond could be coordinated through one agency or a private advertising firm.

***Relative Score = 4.1***

***Status - No action taken, This coordination step is a low priority for some agencies relative to other issues.***

## Marketing Barrier 3 - Curtailments Seen by Customers as Lowering Comfort and Productivity Levels.

Many customers perceive that curtailing peak facility loads cannot be accomplished without a significant drop in plant or personnel productivity.  They are either unaware or not convinced that most building systems have the technical capability of reducing loads by ten percent with little or no effect on employee productivity.

**Action 3.1 -** Energy Commission should produce case studies of customers who have enhanced the automation levels at their facilities and achieved ten percent reductions in load without any loss in productivity.  This enhanced automation campaign should be coordinated with other agencies to sell the message that demand response does not have to hurt.

***Relative Score = 3.75***

***Status - Action taken.  Ten case studies of building owners who have installed enhanced automation have been produced. Energy Commission staff is making efforts to coordinate this message with other agencies.***

## Marketing Barrier 4 - Program Cost Recovery is Very Uncertain in the Current Regulatory Atmosphere.

Most utilities have expressed serious concerns (outside of regulatory arenas) about the prudence of spending money to recruit more customers into demand response programs or tariffs under the current regulatory regime where cost recovery is at best highly uncertain.

**Action 4.1** - Rely on the CPUC to resolve the utilities' credit problems in a timely manner.

***Relative Score = 4.75***

***Status – Action taken. The CPUC and utilities are working diligently to resolve their credit problems.***

# Section 7: Next Steps - Implementing the Action Plan

Based on the feedback received from workshop participants on the relative priority of the action items reviewed above, staff recommends the Energy Commission focus on the following four highest priority actions listed below.

Policy Actions to be Pursued with High Priority Rankings (4.3 and above)

1.1a The Energy Commission and CPUC should work together to develop common vision of a desirable future electricity market structure and rate designs.

1.1b The Energy Commission and CPUC should work together to set customer participation goals to meet long term demand response or emergency response goals, after performing pilot tests to determine customer short term demand elasticity with respect to hourly price changes and performing the necessary cost-effectiveness analysis.

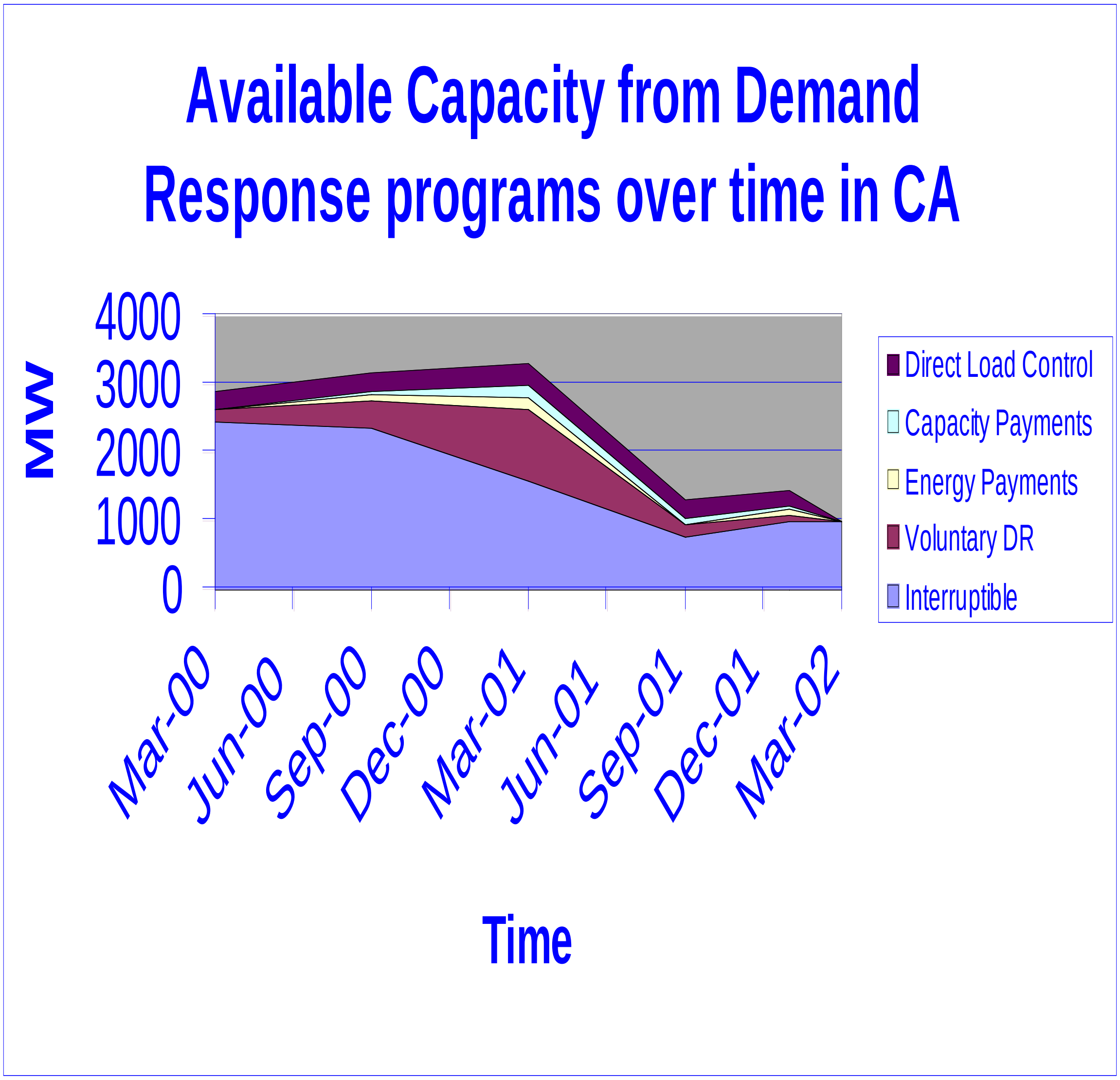
1.2 The Energy Commission and CPUC should work together to integrate demand response tariffs and programs into a re-designed electricity market structure.

4.1 The state should develop and make dynamic tariffs available for all customer classes within the next decade.

On July 17, 2002, the Energy Commission adopted an order instituting information gathering and rulemaking to pursue these actions. Other lower priority goals with average scores of 3.2 or higher will be pursued as staff resources permit. The list of actions ranked by priority based on average responses from the workshop participants is available in Appendix C.

# Appendix A

## Demand Response Capacity (MW) Over the Last Two Years



# Appendix B
## Energy Commission's Current Load Management Authority

(Section 25403.4 Public Resources Code)

The Energy Commission shall adopt load management standard by regulation for a program of electrical load management for each utility service area. In adopting the standards the commission shall consider, but need not be limited to, the following load management techniques:

(1) Adjustments in rate structure to encourage use of electrical energy at off-peak hours or to encourage control of daily electrical load. Compliance with such changes in rate structure shall be subject to the approval of the Public Utilities Commission in a proceeding to change rates or service.

(2) End use storage systems that store energy during off-peak periods for use during peak periods.

(3) Mechanical and automatic devices and systems for the control of daily and seasonal peak loads.

# Appendix C
# List of Action Steps Ranked by Relative Importance

| | | | |
|---|---|---|---|
| **Results from Stakeholder Feedback on Action Plan at May 21, 2002 Workshop**<br>*Actions ranked from highest to lowest level of importance based on average score from 27 respondents* | | | |
| ***Action Step # (1)*** | ***Listing of Action Steps Considered at the Workshop*** | ***Support Action ?*** *(Answers: Yes (Y), No (N), or More Info needed (MI)* | ***Average Relative Importance Ranking by Action:*** *5=Most important, 3=Important but not critical, 1=Not necessary or important* |
| Key PB = Policy Barrier, TB = Technical Barrier, AB = Administrative Barrier and MB = Marketing Barrier | | | |
| MA-4.1 | Rely on CPUC to resolve utility credit problems in a timely manner and allow them to procure energy supplies again | Y=14, N-3, MI=10 | 4.75 |
| AB-1.1 | CA agencies should develop long term customer participation goals for dynamic tariffs after assessment of the results of pilot test results | Y=18, N=4, MI=6 | 4.7 |
| TB-3.1 | Form a working group to explore if demand response programs and/or tariffs can be counted on by UDC's as part of reserve requirements in WSCC definitions | Y=21, N-3, MI=3 | 4.5 |
| TB-5.1 | The CA agencies should support the development of more user friendly EMS systems and build off CEC building automation campaign | Y=16, N-4, MI=7 | 4.5 |
| PB-1.2 | The CEC, CPUC, and CAISO should make a commitment to integrate demand response programs or tariffs into the redesign or reform of wholesale electricity markets | Y=21, N-2, MI=4 | 4.4 |
| PB-1.1 | The CA energy agencies (CEC, CPUC, CPA, and CAISO) should work together to develop and distribute a common vision of a desireable electricity market and rate structure | Y=22, N-1, MI=4 | 4.36 |
| AB-1.1 short | Develop a pilot test of the impact on UDC billing systems of placing 100 to 500 customers on dynamic or hourly rate structures | Y=17, N-6, MI=4 | 4.2 |
| AB-3.1 | Solve the dispute related to how to calculate and pay for the value of reducing load at the margin in either the CPUC procurement proceeding or CEC load management proceeding | Y=17, N-3, MI=7 | 4.1 |
| MA-2.1 | The CA agencies should meet and confer to develop coordinated demand response message | Y=21, N-2, MI=4 | 4.1 |
| PB-1.3 | The CA agencies should meet to discuss how to develop common planning forum to approve/set/coordinate demand response programs and dynamic rates over a multi-year period | Y=22, N-2, MI=3 | 4 |
| PB-4.1 | The CEC and CPUC work together to make dynamic tariffs available to all customer classes during next decade | Y=24, N-1, MI=2 | 4 |
| PB-5.1 | The CEC and CPUC should announce their intention to pilot test the effectiveness of critical peak pricing tariffs in a representative sample of customers | Y=23, N-2, MI=2 | 4 |

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3. Chris King, E-meter, "*Civil War Shoulder Arms or How New Technology Can Change the Rules of the Game,*" presentation at Energy Commission Demand Response Workshop, Sacramento, California, March 15, 2002.

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10. Karen B. Herter, Roger Levy, John A. Wilson, and Arthur Rosenfeld. *Rates and Technologies for Mass Market Demand Response* (paper in ACEEE Summer Study Proceedings on Energy Efficiency in Buildings. August 2002 Volume 5.

11. Brian White, "Good Cents Select Price Responsive Load Management," presentation at Energy Commission Demand Response Workshop, held in Sacramento, California, March 15, 2002.


Readers who want to access some of these presentations via the internet can download them at [http://www.energy.ca.gov/peakload/documents/2002-03-15_presentations/].